THE LONG-TERM SUSTAINABILITY OF DOMESTIC NATURAL GAS SUPPLY

Report on ongoing work at
The U.S. Department of Energy's

STRATEGIC CENTER FOR NATURAL GAS

at the

NATIONAL ENERGY TECHNOLOGY LABORATORY

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Executive Summary

As part of an ongoing program in Resource and Reserve Assessment at the National Energy Technology Laboratory (NETL), the Strategic Center for Natural Gas (SCNG) will coordinate and lead a study to assess the long-term sustainability of domestic natural gas supply in the United States. The work builds on over two decades of NETL's management of the Department of Energy's (DOE's) Natural Gas Program. The initial work will focus on the Rocky Mountain basins where future supply from non-conventional resources are projected to nearly double by 2015 and where access to Federal lands could have an impact on future gas supplies. SCNG will work with other federal agencies, e.g., the U.S. Geological Survey (USGS), the Energy Information Administration (EIA), and the Bureau of Land Management (BLM), to bring expertise as necessary. The importance of this effort is highlighted in the 1999 National Petroleum Council (NPC) study, *Meeting the Challenges of the Nation's Growing Natural Gas Demand,* which recommended establishing a balanced, long-term approach for responsibly developing the nation's natural gas resource base.

Based on the 1999 NPC study, natural gas will make an important contribution to the nation's energy portfolio well into the twenty-first century. The demand for natural gas can be met with U.S. production, along with increasing imports from Canada. However, to realize the full potential for natural gas use in the U.S. (almost 30 trillion cubic feet (Tcf) in 2010), the NPC recognizes that significant challenges must be met by industry and will require substantial support on key issues by the government. Resources at depths greater than 15,000 feet, offshore resources in water depths over 4,000 feet, and non-conventional resources will be key to future supply. Two regions in particular – deepwater Gulf of Mexico and the Rocky Mountains – will contribute most significantly to new supply.

A series of sensitivity analyses provided some insight regarding the importance of various critical factors. The single most significant assumption was the size of the resource base. The price of gas could be lowered by as much as $0.96 per million Btu in 2010 if the economically recoverable resource base were found to be 250 Tcf larger than assumed in the reference case. Both faster upstream technology advances and increased access could also have significant impact on natural gas price and demand.

Out of their seven recommendations, Recommendation 2, *Establish a balanced, long-term approach for responsibly developing the nation's natural gas resource base,* is being addressed in this report. SCNG is in a unique position to address the NPC's recommendation for long-term gas sustainability because of its role in managing the Natural Gas Program. Past SCNG research has been a major factor in increasing industry awareness and expectations, and providing the technologies needed to make significant gas production from non-conventional resources a reality.

This work builds on SCNG's expertise by defining a more robust, integrated approach to analyze resources and reserves of major gas basins and to determine the impact of advanced technologies. By using an integrated approach, from resource characterization to technology assessment, SCNG will begin to identify technology needs that can drive the DOE Natural Gas R&D program and provide objective analyses of natural gas policy issues. In addition, SCNG will address access restrictions where they are imperative, e.g., the Rocky Mountains, to

determine the impact of access restrictions, prioritize the resource potential of restricted areas, and begin to address environmental sensitivity.

1. Overview

In 1998, the U.S. Secretary of Energy requested the National Petroleum Council (NPC) to reassess its 1992 report *Potential for Natural Gas in the United States*, taking into account several major factors:

- The significant restructuring of the gas industry resulting from Federal Energy Regulatory Commission regulations
- Strong U.S. economic growth
- The restructuring of the electricity markets
- The remarkable progress in technology
- Growing concerns about air quality

In December, 1999, the NPC issued their report which concluded: 1) natural gas can make an important contribution to the nation's energy portfolio well into the twenty-first century; 2) the resource base is adequate to meet the increasing demand for many decades; and 3) technological advances continue to make more of the resource technically and economically available. However, the NPC cautioned that to realize the full potential for natural gas use in the U.S. certain critical factors must be addressed including:

- Access to resources and rights of way
- Continued technological advancements
- Financial requirements for developing new supply and infrastructure

In addition, the NPC recommended that government agencies and industry representatives establish a balanced long-term approach for responsibly developing the nation's natural gas resource base and continue the work begun by NPC to inventory existing information on the resource base in the Rocky Mountain region and analyze the impact of access restrictions.

As part of an ongoing program in Resource and Reserve Assessment at the National Energy Technology Laboratory (NETL), the Strategic Center for Natural Gas (SCNG) will coordinate and lead a study to assess the long-term sustainability of domestic natural gas supply in the United States. This effort will tie together ongoing SCNG programs of resource characterization and gas systems modeling to provide a better understanding of three key issues impacting long-term gas supply; 1) the size and nature of the resource base critical to future supply; 2) the type of future technologies needed to allow the timely conversion of resources into reserves, and 3) the impact of selected federal policies on future supplies, particularly those related to industry access to resources on Federal lands. The work will be an integral part of the SCNG's mission to guide and coordinate the DOE's Natural Gas Program and to provide objective analyses of natural gas policy issues.

1.1 Long-Term Gas Supply: Domestic Resources

Concerns over the long-term sustainability of domestic gas supply first came to prominence with the energy crisis of the early 1970s. At that time, the total domestic resource base was estimated to be roughly 1,000 trillion cubic feet (Tcf) of gas – nearly half of which had already been consumed. From this information, Dr. M. King Hubbert estimated that domestic natural gas production should peak at 23 Tcf per year in 1977, then decline dramatically to levels of roughly 10 Tcf per year by 1996. Hubbert's projections, which had already proven accurate relative to domestic oil production, spurred government and industry to action. With time, advances in technology allowed for more efficient recovery of the known resource and, most importantly, the addition of unexpected and prolific new resources such as the deep offshore, coal beds, and tight sandstones. By the 1990s, the technological successes of the previous two decades resulted not only in the abatement of gas supply concerns, but provided justification to envision the environmental and economic benefits of vast increases in gas use.

Today, nearly 30 years and 500 Tcf of gas production after Hubbert's report, the Potential Gas Committee (PGC, 1998) now estimates a total domestic resource base of 2,117 Tcf, with 913 Tcf produced and 1,205 Tcf available for future supply. In comparison, the 1999 National Petroleum Council (NPC) study (see Appendix 4) estimates that 1,466 Tcf of technically-recoverable gas may yet remain in the ground in the lower 48 states. Not only is the remaining resource large, but estimates of its size have increased through the years. The PGC's estimate of remaining resource has grown with each biennial assessment since 1992. Likewise, the NPC's 1999 estimate is 171 Tcf greater than that presented in their 1992 report, even though 124 Tcf of gas was consumed in the interim. The major reason for this growth is clearly technology advance. With each year, more resource that was previously excluded from consideration as simply too complex or costly to produce, is found to be technically and economically recoverable.

Despite this good news, we should not conclude that there is a ready supply of gas that will last 50 years or more. Of the total resource, only 170 Tcf is *proved reserve*, or gas currently available for production. The rest, more than 1,200 Tcf, is *potential resource* - gas awaiting discovery, improvements in E&P technologies to reduce finding and producing costs, or natural gas price increases. Furthermore, the rules of Hubbert's curve remain, and gas production rates are likely to reach their peak once one-half of the ultimately recoverable resource is consumed. If the growth in recoverable resources slows, perhaps as a result of either reduced investment in technology or reduced success of technology, the projected rates of gas consumption could easily push the U.S. to this critical point within the next 15-20 years. Consequently, the issue of the sustainability of long-term gas supplies has re-emerged, fueled by two observations; 1) demand is rising rapidly; and 2) the remaining resource base is becoming progressively more costly and complex to produce.

1.2 Long-Term Gas Supply: Demand Assessments

A general consensus has emerged that gas use will continue to expand, reaching unprecedented levels of 30 Tcf per year or more as soon as 2015 (Table 1). EIA's latest Annual Energy Outlook (AEO) and the recent NPC study (both published in December, 1999) agree that gas use will expand, along with the economy in all end-use sectors, with particularly rapid expansion for electric generation. Although NPC's estimates of future demand are slightly lower than other projections, the NPC notes that future environmental legislation could result in considerably higher demand than projected.

Table 1: *Comparison of Natural Gas Demand (Tcf) and Price ($/Mcf) Projections*

Assesssor	2015 Demand/Price	2020 Demand/Price
EIA, Annual Energy Outlook 2000	29.9 / $2.71	31.5 / $2.81
WEFA	32.5 / $2.51	34.6 / $2.66
GRI Baseline Projection	31.2 / $2.39	-
DRI	30.0 / $2.41	31.2 / $2.65
American Gas Association	30.1 / $2.33	-
National Petroleum Council (Dec. 1999)	29.0	31.3

At the same time demand is rising, it is widely recognized that our domestic resources are become progressively more difficult and costly to produce. The NPC notes that the bulk of the increase in gas supplies over the next two decades must be born by deep gas, deepwater gas, and non-conventional resources. "All of these new sources of gas require that significant technology hurdles be addressed and overcome in order to deliver cost-competitive supply (NPC 1999)". The various assessors are uniformly confident that these challenges will be met, as their reference cases predict that 30 Tcf per year can be produced and delivered to market without substantial increases in price, at least through 2020 (Table 1). Nonetheless, both studies by the NPC and the EIA point out that failure to reach these technology goals could result in significant price impacts. NPC estimates that slow technology growth could result in a $0.27/thousand cubic foot (Mcf) rise in gas price by 2010, costing gas users an additional $8 billion annually. NPC also reports that if the resource base is found to be 250 Tcf smaller than now estimated (a possible outcome of limited technology advance or access restrictions), the price impact in 2010 could be as much as $0.56/Mcf (a $17 billion increase). Similarly, the EIA's AEO projects that slow technology advance could raise gas prices by as much as $0.94/Mcf by 2020, adding nearly $30 billion to gas users costs.

In general, the overall optimism of these projections is derived from a combination of 1) abundant resources, 2) a shared assumption that technology progress (and its impact) will continue at past rates, and 3) restriction of the projections to the period before 2020. While the SCNG shares the belief that the resource is potentially huge, we also understand that abundant resources do not necessary mean timely and abundant reserves. In our role as co-developers of the nation's energy technology portfolio, we can not assume that a business-as-normal approach will continue to produce breakthrough technologies at the pace of the last two decades. This view is supported by recent downward trends in both industry and government expenditures for R&D that targets the high-risk, low-quality reservoirs that are expected to make up a growing proportion of the remaining domestic potential resource. This view is shared by NPC, who noted that "investment in research and development is needed to maintain the pace of advancements in technology".

A final point regarding the current assessments – none project past 2020. However, the SCNG's mission is to work with industry to develop technologies that will enable gas production to contribute over the long-term, and to remain a significant contributor to national energy supply until such time as the next generation of sustainable energy sources are available.

1.3 Ongoing Work at NETL

For over two decades, NETL has implemented DOE's Natural Gas Program. The bulk of NETL's work has focused on fostering advanced technologies for the appraisal and production of onshore non-conventional reservoirs. The reasons for this focus on the non-conventional include the following: 1) the resource base was suspected to be vast (over 5,000 Tcf in the Greater Green River Basin alone); 2) development of the resource would clearly be driven by the availability of advanced technology; and 3) industry was not actively pursuing R&D in these regions, opting instead for the larger stakes offshore and overseas.

In order to quantify the magnitude of the non-conventional gas resources and reserves, NETL has worked with the USGS and the Scotia Group to provide assessments of the volume and nature of non-conventional gas resources (see Appendices 1-3). In addition to the benefit these studies have provided in accelerating industry entry, this work has helped set the R&D priorities for NETL's efforts in drilling cost reduction, improved stimulation, advanced diagnostics and imaging, and other areas. NETL's work has reduced and will continue to reduce the costs and risks of gas production in many geologically complex settings.

To provide quantitative support for program planning, SCNG has developed the nation's most sophisticated model of the natural gas production/transmission/utilization system. The Gas Systems Analysis Model (GSAM) was designed to allow policies and technologies to be modeled in great detail, not only in their specific impacts, but also in the degree and timing of their utilization. The latest improvements to this model allow for fully integrated runs to be conducted in light of characterizations of future demand, as well as storage and transmission capacities.

2. SCNG's Integrated Approach to Studying Long-Term Gas Supply

SCNG has recently completed an internal assessment of its resource characterization and technology modeling activities and found that these two efforts were not well coordinated. First, the models were not utilizing the resource characterizations, even though these data were, in some cases, more properly suited for the model than the data being used. Similarly, the resource characterizations were not uniformly collecting the type of data needed to assess the role of advanced technologies. In addition, resource assessments for several key plays/basins were out-of-date or not yet attempted.

As a result, SCNG has begun a new initiative to improve and integrate these two program elements. Central to the effort will be a regular effort of tracking industry activities relative to key resource segments. This new effort in industry tracking will provide quarterly updates of permitting, drilling, production, and technology utilization that will support program planning, provide insight into the planning of resource assessments, and support modeling by providing ground truth to key technology assumptions.

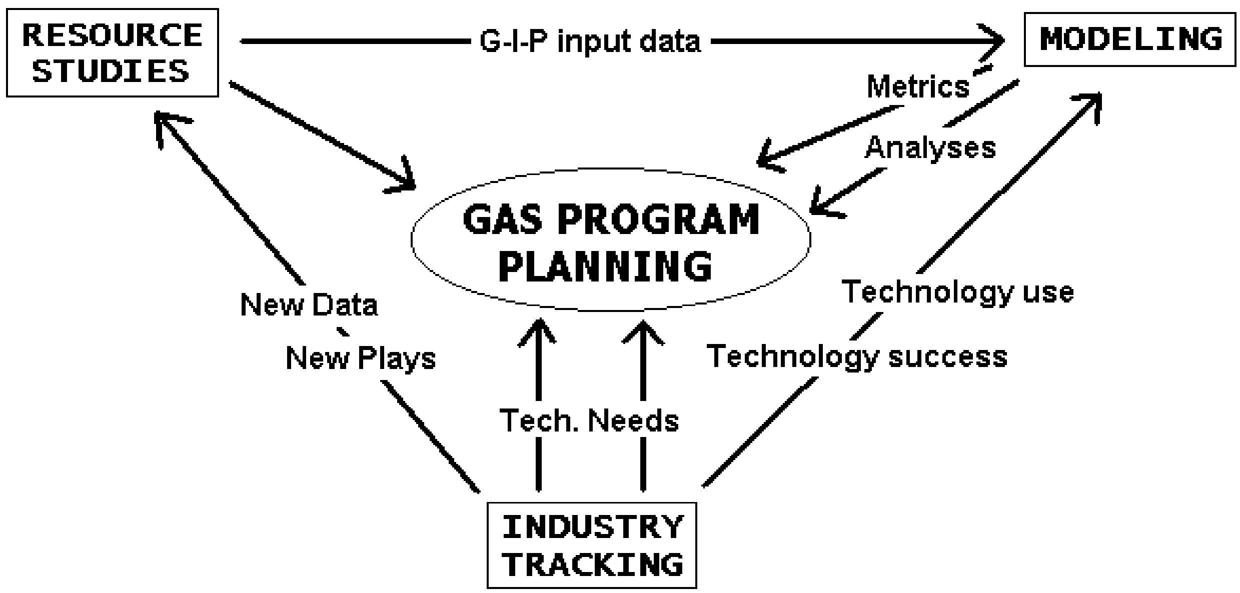

Figure 1: *Schematic of SCNG's integrated approach for planning R&D to meet the challenges of long-term gas supply sustainability*

All three pieces of this effort will be coordinated by SCNG's staff with the goal of providing information and analyses to support gas program planning and implementation. Key to this work will be the modeling of the pace and nature of future technology development and its impact, and issues of land access. The effort will be collaborative, with SCNG personnel conducting most of the modeling work. SCNG, Advanced Resources International (ARI), EIA, USGS, and the BLM will work together as necessary to provide the data and expertise needed to guide the effort. This effort supports the SCNG in its two primary missions: 1) to support departmental R&D planning and implementation; and 2) to provide policy-makers with detailed information on the impact of alternative future technology and policy scenarios on the long-term sustainability of gas supply.

The kick-off date for the integrated program for analyzing long-term sustainability of natural gas supply was October 1, 2000. The first phase of work, to be completed by December 2001, will focus on two major basins of the Rocky Mountains, the GGRB and the Wind River. Subsequent phases will target additional key resources. The choice to start in the Rockies is based primarily on the established presence of a large resource that depends on continued technology advance to become economic. In addition, the area contains significant Federal lands, and thereby provides an excellent opportunity to simultaneously model the impact of alternative technology and policy scenarios. Furthermore, the team contains a wealth of experience in studying the area – the past efforts in the region by the USGS, NETL and ARI ensure a quick start-up to the effort (see Appendices 2,3 & 6). The effort will proceed as follows:

- ♦ Detailed gas-in-place resource assessments suitable for use in the SCNG's gas models will be produced.

- ♦ GSAM's various databases that characterize the current state of infrastructure capacity, reserve growth, regional prices, demands, and other information will be updated and validated. Further improvements to GSAM's modeling capabilities relative to Federal lands, non-conventional resources, and other issues, will also be made.

- An industry tracking activity, providing quarterly updates and yearly summaries of drilling, technology use, and other information that can serve to ground truth many modeling assumptions, will be conducted.

The following sections discuss the methodology of these efforts.

3. Resource Characterization

The goal of the renewed resource characterization effort will be to collect information useful not only to industry, but also to DOE R&D program planners by being tailored for input into SCNG's technology/policy models. These assessments will approach, as closely as practical, the total resource-in-place, and will disaggregate the resource as much as possible relative to specific technology and cost-sensitive parameters. These assessments will improve analyses of future gas supplies under a wide range of time frames and technology/policy scenarios.

This work will be a continuation of more than a decade of close cooperation between SCNG and the USGS (see Appendix 2). Beginning with the landmark study of the Greater Green River basin, published in 1989, the USGS has provided assessments of the gas resources in-place in key western basins. These studies quickly became controversial, as the rigorous methodology resulted in estimates that were shockingly large to those accustomed to the standard technically recoverable resource numbers. Nonetheless, these studies were important, providing the initial quantification of the vast "unrecoverable" resource, and therefore provide the starting point for the current work.

The need for a gas-in-place resource description is simple. We cannot accurately assess the role of various alternative technology futures using an input data set that pre-supposes a single technology case (Figure 2). Most assessments, including the 1995 USGS national assessment upon which SCNG modeling data sets are currently based, deal with only a small fraction of the total in-place resource. This volume, which is called the *technically recoverable resource*, consists of current reserves (approximately 170 Tcf), a larger portion that is expected to be produced with current technologies (from 800 to 1,200 Tcf), and an additional increment that should be recoverable in the future as technologies improve (roughly 200 Tcf). Typically, the remainder of the resource-in-place is excluded from the recoverable resource picture. (It is interesting to note that in past decades, "unrecoverable" resources have included coal-bed methane, shale gas, and tight sandstones, which currently account for over 25 percent of Lower-48 gas production). Therefore, the technically recoverable resource is *static* in that it is based on a single set of technology/cost/policy assumptions for a single given time frame. In addition, the assessors do not describe the future technologies, or how, where, or when they will be applied. Instead, technology advance is generally defined by extrapolating past trends toward increasing recovery factor and/or decreasing cost into the future.

Therefore, for those with the responsibility to plan the R&D and policy programs that will impact future reserves over the near, mid- and long terms, *singular* recoverable resource estimates lose their value. Consequently, SCNG will work to produce the type of resource characterizations that is required to analyze a wide variety of alternative technology, cost, and policy scenarios.

In order to allow these analyses to be more sensitive in quantifying and/or ranking the potential contribution of specific technologies (or technology areas), the resource description must be highly disaggregated, i.e., divided into as many categories (depth, pressure, etc.), as needed. Disaggregation will allow analyses to determine which particular reservoirs will benefit from each technology advance, and how large the impact might be. Existing gas-in-place estimates will be revisited for selected areas to update data and collect additional information on the various geologic conditions of the gas resource. In addition, new studies in non-assessed areas, both conventional and non-conventional, will also be part of this effort.

4. Technology Modeling

The collection of detailed geologic data on the gas-in-place will be of little use without the means to analytically process the data to determine the impact of specific technology/cost/policy scenarios. In 1990, NETL commissioned the development of a model for just this purpose. The Gas Systems Analysis Model (GSAM) has been used by NETL since 1995 to support internal project planning and metrics analyses. GSAM's upstream modules provide analyses of the role of specific future technology and policy scenarios on the potential production volumes and economics of over 20,000 gas reservoirs (discovered) and play/field-size classes (undiscovered).

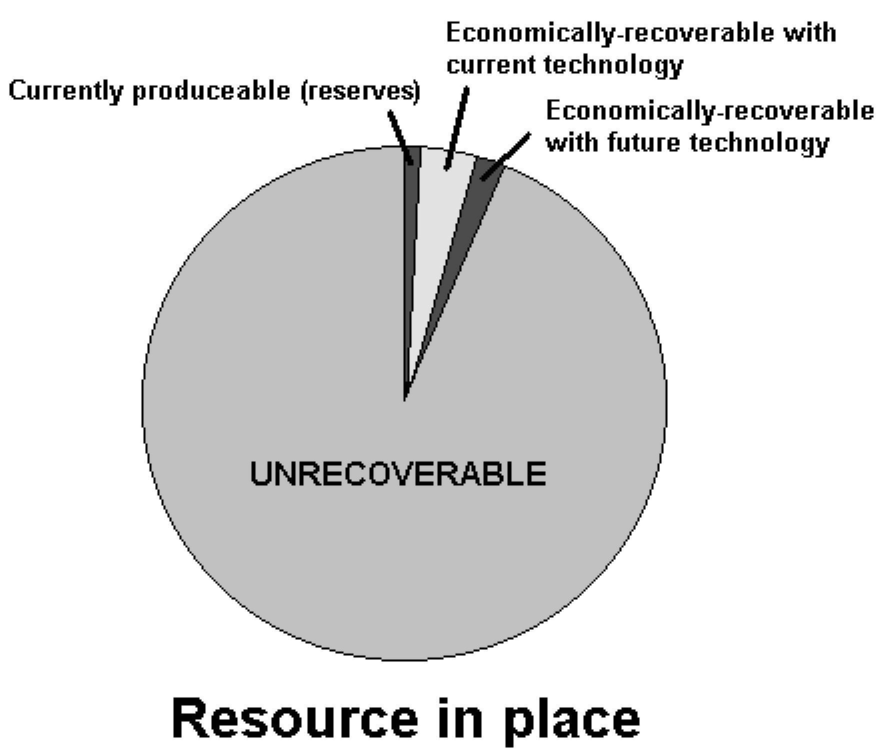

Figure 2: *Schematic description of the key segments of the total in-place resource*

The downstream modules estimate future supplies and demands given a set of drilling capacities, technology penetration, GNP and population trends, and end-use characteristics. The integration modules balance supplies and demands by season and end-use sector in light of storage and pipeline costs and capacities to provide final, balanced, price and supply projections. An example of GSAM's capability is provided in Figure 3. GSAM's RP module uses dimensionless type curve analyses to estimate the production of individual resource elements. The production modeled by these curves is dependant upon the interaction of the specific geological/engineering characteristics of each reservoir with several key technology-dependent parameters such as skin and fracture half-length. In Figure 3, the pink line might represent technologies by 2020, the green by 2030, and the blue by 2040 (or they may all represent 2020 technologies, but assuming different policies or funding levels).

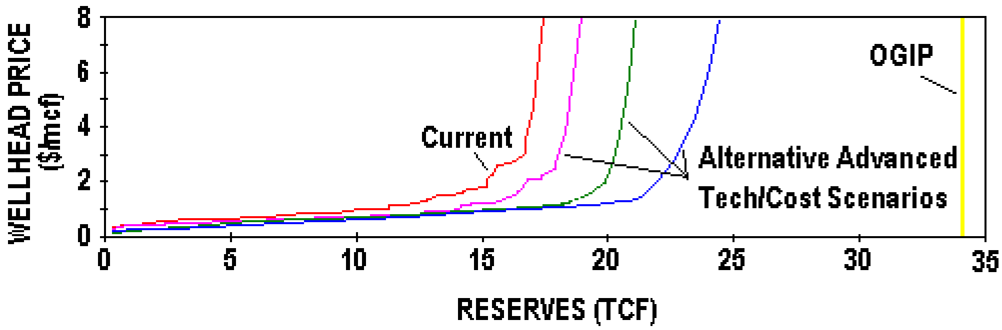

Figure 3: Example of GSAM capability

Because of the level of detail with which GSAM operates, and its ability to model the impact of technologies, GSAM will form the nucleus of SCNG's modeling efforts. As part of this ongoing effort, SCNG will investigate how to improve GSAM (see Appendix 7), and will work to further expand GSAM's capabilites. Currently, GSAM utilizes the Nehring (NRG) database as the source for data on discovered fields. A small number of "pseudo-reservoirs" are added to account for the contribution of the small fields that are excluded from NRG's database. EIA data are used to support addition of resources through reserve growth. For undiscovered resources, the model relies on the 1995 USGS national assessment. Because the model needs a gas-in-place estimate to work properly, GSAM estimates gas-in-place for each reservoir by applying an average recovery factor, thereby inflating the assessed recoverable volumes to something *approximating* gas-in-place. This method has several shortcomings: specifically, only fields included in the USGS assessment are included, and the natural variability in recovery factor is not preserved. For example, the 6,000 Tcf of gas assessed to be in-place in the Greater Green River Basin by the USGS is not represented in the database – in fact, the entire GSAM resource base is slightly more than 2,000 Tcf. Thus, a major improvement will be provided by the new resource base characterizations as they are completed.

Additional code changes needed to improve the reliability of the model will be evaluated and implemented by SCNG's site support team, including ICF Consulting, Inc., the developers of GSAM. For example, GSAM works exclusively with field-size classes and their expected distributions – a concept that may not be applicable to the continuous, basin-centered deposits that form a major portion of the "unrecoverable" resource and are the likely targets of much of DOE's R&D effort. Other areas of potential improvement are GSAM's treatment of horizontal well drilling and the technology penetration function.

Of particular importance to analyses that focus on low-permeability sandstones is the ability to accurately model the impacts of restricted land access. The need for such analyses was a major recommendation of the 1999 NPC. Although SCNG will not attempt to determine the relative value of environmental protection and resource development, it is clearly part of our mission to provide objective analyses of the impacts of these legislations, so that those who do make policy can do so with the most complete information. Therefore, wherever land access is an issue, SCNG will take the necessary steps to collect the data, modify the models, and conduct the necessary analyses.

5. Industry Tracking

Industry activities will be tracked continuously with quarterly updates on industry permitting, drilling, completion, stimulation, and production data for major tight gas plays. The data will reveal where industry is active and what technologies are being used. In addition, data and case studies will be collected regarding the evolution in application of advanced technologies. This tracking activity will be based on publicly available literature and reports, as well as regular visits with the major operators and regulators in the nation's emerging natural gas plays. The result will be that SCNG managers will have up-to-date information on what technologies are being used and how they are being applied, what technologies are not being used and why not, and what impact the technologies had on costs, production and other parameters.

SCNG views this activity as a critical link in this new initiative to provide gas program managers with the latest and most relevant data. In addition to supporting the formulation of the program R&D portfolio, the industry tracking reports will help set the priorities for the ongoing program of resource assessments, providing inputs on areas with sufficient data to warrant new or revisited studies. In addition, the tracking of technologies will allow SCNG to test the technology utilization and impact estimates incorporated into its models.

6. Federal Lands Assessment

The 1999 NPC report contained a first time assessment of resource impacts associated with federal land use designations and related environmental stipulations in the Rocky Mountain region. This was accomplished through a cooperative effort of industry and Federal agencies, including the DOE, BLM, and the U.S. Forest Service. This analysis was based on a very limited sample of Federal lands and extrapolated throughout the U.S. The NPC recommended that this cooperative approach be continued and expanded to better quantify the interaction between land use and the natural gas resources of the Rockies. As such, a study is being led by DOE-HQ to collect and analyze data on federal land use in the Rocky Mountain basins – Greater Green River, San Juan, and Uinta/Piceance (and possibly the Wind River).

The long-term sustainability study being conducted by SCNG and the federal lands assessment being led by HQ will be closely coordinated. SCNG will provide the majority of data on gas-in-place estimates and conduct GSAM modeling runs to determine the impact of technology and access restrictions. The DOE-HQ study will provide the majority of data on federal land use designations, including the types of restrictions. Thus, these two studies will provide the data necessary (gas-in-place, technology assessment, access impacts) so policy makers can have the best available data in making decisions on how best to produce its valuable gas resources while protecting the environment.

APPENDIX 1: Review of Major Low-Permeability Resource Studies

This program for ongoing work at SCNG will be conducted in the light of numerous previous studies. Our work will focus initially on our area of expertise, low-permeability sandstones, but will expand to include all resources relevant to the issue of long-term supply. The following is a review of previous low-permeability resource studies provided to SCNG by site-support contractors EG&G and ARI. These reviews were conducted to help SCNG determine the nature of the resource data available and to evaluate the types of additional data and information needed to support R&D program planning.

The summary findings of this review were as follows:

- There is a strong need for a consistent and reliable information system that tracks industry's activities in developing marginal, technology-intensive, resources. This recommendation forms the basis for the industry tracking effort described in the main body of the report.

- The existing low-permeability natural gas resource appraisals can and need to be improved. The focus should be on 1) the sub-economic and currently unrecoverable portions of the resource base, and 2) collecting the information needed to accurately model marginal resources. Resource assessments should include information on the reservoir properties that control gas recovery, thereby providing insight into the technological barriers that must be overcome before these resources can be added to the nation's reserves.

- Third, the full scope of tight gas resources need to be appraised and incorporated into all analyses. This will entail updating earlier studies, completing work-in-progress in the Rocky Mountain region, and undertaking new efforts for the Mid-Continent, West Texas, Gulf Coast, and other major gas basins and plays.

Specifically, the review focused on the work of the NPC, the USGS (both the national assessments and the in-place studies conducted in cooperation with NETL), and The Scotia Group. The detailed findings were as follows:

- The USGS gas-in-place studies (Appendix 2) provide an invaluable base of information, and should form the basis for ongoing efforts. These reports highlighted the concept and importance of basin-center gas formations, providing rationale for off-structure exploration and development of overpressured, low-permeability reservoirs. They also provided confidence that truly massive volumes existed in these basins, providing the impetus for accelerated and targeted technology development. Finally, these studies reaffirmed that a combination of sweet-spot/natural fracture detection and advanced drilling/completion would be required.

- However, much of the USGS's in-place assessment work is now dated (in particular the 1987 Piceance basin and 1989 Greater Green River basin studies) and the information gained over the past decade needs to be incorporated. Also, the USGS studies, particularly the earlier two, do not provide the detailed disaggregation of the resource that would be needed to support the types of technology modeling envisioned in this effort.

- The studies by The Scotia Group (Appendix 3) provide valuable insight into the USGSs in-place resource estimates. However, Scotia's work to quantify current recoverable volumes does not relate well to the type of information needed by SCNG. In many basins, Scotia's work discards 80% or more of the resource as "technically non-viable" without discussion as to the specific conditions and barriers that make these resources too costly to produce. Furthermore, as with all assessments that are tied to the specific technology of a given time, the studies will quickly became obsolete and not amenable to renewed assessment with different technology assumptions.

- The NPC assessments (Appendix 4), being based on a particular set of technology assumptions, are similarly not amenable to modeling of alternative future technology/policy scenarios. In addition, these studies do not appear regularly, and are not always based on the latest data (the NPC's 1999 report was based primarily from assessments taken from the 1992 study, which was, in turn, based largely on the 1980 study).

- The USGS National Assessments (Appendix 5) have limited utility for SCNG's technology planners and modelers. Unfortunately, the USGS did not recognize tight gas as part of the national resource base for their 1989 national assessment. These resources were included for the 1995 assessment, however, several major basins (such as Wind River, Anadarko, and Fort Worth) were not appraised. The appraisal methodology relied on the extrapolation of historical data on well performance and development practices and therefore did not incorporate the role of future technologies in any detail.

The following provides brief descriptions of additional resource studies that have contributed to our present understanding of the nation's tight gas resources.

- *1973 Federal Power Commission*: The FPC assembled an industry panel to provide an initial review of the tight gas resources of the Green River, Piceance, and Uinta basins. The study estimated a resource base of 600 Tcf gas-in-place.

- *1978 Federal Energy Regulatory Commission:* FERC's report relied heavily on the FPC study, and added assessments of the tight gas-in-place for the Northern Great Plains (130 Tcf) and San Juan basin (63 Tcf).

- *1978 Lewin and Associates:* Lewin and Associated provided the initial comprehensive appraisal of tight gas resources. Thirteen high-potential basins were studied. The work was conducted at a play level, allowing for substantial improvement in the estimation of missing data. Lewin used type-well productivities and mapping of prospective areas to estimate 423 Tcf gas-in-place in tight formations. The study excluded formations below 13,000 feet.

- *1990-1991 ICF Resources*: Under sponsorship from DOE/METC, ICF conducted detailed field level studies to determine remaining gas-in-place and expected recoverable volumes (at current technology and $2.00 price) for tight gas formations in East Texas (31 Tcf in-place, 6.2 Tcf recoverable) and the San Juan basin (17 Tcf in-place, 2.3 Tcf recoverable).

Table 1 provides selected results from these early efforts. This work provided the foundation for the 1988 Study for the Secretary of Energy by the Bureau of Economic Geology (BEG) and ICF-Lewin as well as the 1992 study by the NPC. It was these latter two landmark studies that helped to establish industry and public acceptance of the potential of low-permeability reservoirs to be major contributors to domestic gas supply.

Table A1-1: Selected findings of early tight-gas resource assessments (Tcf gas-in-place)

	FPC '73 – FERC '78	LEWIN 1978
Northern Great Plains	130	74
Greater Green River	240	91
Uinta	210	50
Piceance	150	36
Wind River		3
Big Horn		24
Douglas Creek Arch		3
Denver		19
San Juan	63	15
Permian/Val Verde		24
Edwards Lime		14
E.Texas/Cotton Valley		67

Other studies of note include:

- *1991-1992 DOE/METC:* METC conducted the initial, and to-date only, extensive well log analysis and mapping to assess the resource potential of the primary low-permeability sandstone formations in the Appalachian basin. The study estimated that 28 Tcf of gas remained in Silurian Clinton sandstones and 25 Tcf remained in the various Devonian and Mississippian sandstones.

- *1995 &1998 Potential Gas Committee*: Similar to the NPC, the PGC assesses gas volumes that can be expected to be produceable in the future under reasonable future prices and foreseeable technology advances. Resource volumes are divided into probable (roughly equivalent to the concept of reserve growth, i.e., extensions and new pools in established areas), possible (not associated with known fields, but in favorable areas), and speculative (in formations/areas not now productive) categories. PGC's methodology is based on expert estimates of the volume of potential reservoir rock , multiplying that volume by an expected yield, and then discounting the resulting volume for geologic risk. Each investigator provides minimum, most likely, and maximum resource estimates.

- *1999 Gas Research Institute*: The GRI uses the Hydrocarbon Model (developed by EEA) to produce their baseline projection.

APPENDIX 2: NETL-sponsored USGS gas-in-place assessments

The resource studies of the late 1970s and early 1980s outlined in Appendix 1 clearly indicated that the Rocky Mountain basins contained significant volumes of gas in low-permeability formations. Estimates of the resource potential of the Greater Green River basin, for instance, had shown from 90 to 240 Tcf gas-in-place. This gas was marginally- to sub-economic at best given prevailing E&P technologies and economics, and therefore became a prime target for federal R&D efforts. Suspecting that the resource was being significantly under-estimated, the USGS and DOE-METC began work to comprehensively assess the resources present in the major basins. This work was conducted independently from the USGS's regular national assessments (see Appendix 5), and employed a drastically different methodology.

For this work, the USGS method was to evaluate the total tight-gas resource-in-place of specific basins through exhaustive volumetric study of vast rock sequences. Only two sacrificies to practicality are noted. First, gas in sandstones less than 10 ft. thick are discarded. Second, gas in normally-pressured sandstones or in units in the transition zone between overpressured and normally-pressure units are not counted in all studies (the GGRB study was limited to the overpressured units). Gas-in-place volumes were determined in the conventional way, with most parameters being based on a sampling of well data or assigned by regional experts. Recoverable volumes were then estimated from in-place numbers by application of estimated recovery factors. A key methodological aspect of these studies is that many of the variables (thickness, porosity, recovery factor, etc.) are expressed as probability functions and processed through a probability model, ultimately yielding a range of possible resource sizes, each with an assigned likelihood of occurrence.

1. 1987 USGS Piceance basin study *(R.C.Johnson and others; USGS open-file #87-357)*

This initial report utilized the ongoing DOE work at the MWX site to provide a resource assessment of the low-permeability sandstones of the Mesaverde Group in the Piceance basin. The Mesaverde was divided into three stratigraphic plays, a lower (dominantly-marine) Iles play, a thin, intermediate Rollins sandstone play, and an upper (dominantly-fluvial) Williams Fork play. Being marine/shoreline in origin, the Iles includes numerous relatively-continuous sandstones (including the Morapos, Castlegate, Sego, Corcoran, and Cozette). The Rollins (or Trout Creek) sandstone, a particularly widespread blanket sand at the top of the Iles sequence, was regarded as separate play because it is persistantly water-bearing. The primarily non-marine sandstones in the overlying Williams Fork play are highly-lenticular and channelized. Each of these three units are divided into basin-center ($R_o > 1.1\%$) and transition (R_o from 0.73% to 1.1%) plays, resulting in six assessed plays.

Total sandstone volumes for each were calculated from isopach maps based on 60 well logs/outcrop sections. All the sandstone in each play was assumed to occur at the play's average depth (with an average overburden) with temperature and pressure based on assumed gradients. Porosity and gas saturations were based primarily on data from the MWX wells. These data were used to create initial in-place resource estimates for each play.

To provide for a probabilistic presentation of these data, each parameter (with the exception of porosity, which is assumed to be perfectly positively correlated with gas saturation) is assigned values at 0%, 50%, and 100% probability levels. The USGS further tweaked the distributions until the two answers matched. These volumes were then aggregated assuming a 75% degree of dependancy between the six plays.

In order to calculate the volumes likely to be recovered under specific cost/technology conditions, recovery factors were estimated. These values were also defined probabilistically. Two scenarios were conducted; 1) current technology with $5.00/Mcf price and 2) advanced technology with unspecified (but high) price. Technology in this case basically means the technical limits on recovery factor.

Table A2-1: 1987 USGS Piceance basin study results (values in Tcf).

PLAY	**Resources**			**Recovery Factor**		**Reserves**	
	Mean	F05	F95	Cur.	Adv.	Cur.	Adv.
Williams Fk.- b/c	205.6	286.9	133.0	3%	15%	6.0	30.1
Williams Fk. - tran.	116.9	189.5	37.7	3%	18%	3.6	21.6
Rollins - b/c	3.4	6.1	1.6	5%	20%	0.2	0.6
Rollins - tran.	0.6	0.9	0.2	10%	22%	0.05	0.1
Iles - b/c	72.0	107.3	20.0	3%	15%	2.1	10.6
Iles – tran.	24.1	39.4	8.0	6%	20%	1.5	4.9
6-play aggregate	419.6	605.3	274.4			13.4	67.9

2. 1989 Greater Green River basin *(B.E.Law and others; Wyoming Geological Association; 40th field conference guidebook, pg. 3 - 25)*

This report describes the GGRB Cretaceous and Lower Tertiary overpressured, tight sequence. The assessment encompasses up to 14,000 ft. of stratigraphic section over an area more than 50,000 km^2 in size. The subject rocks range from alluvial plain to marine basin and include marine shales, marginal-marine sandstones with overall blanket geometries, and highly-lenticular fluvial sandstones encased in non-marine shales with associated coals.

The *Cloverly-Frontier Play* includes the sandstones formed during the initial Cretaceous shoreline regression (extension eastward) in the region. It is the deepest play and extends throughout the basin with the exception of the Moxa Arch, which was excluded due to the presence of conventional reservoirs. The overlying *Mesaverde Play* includes the major Upper Cretaceous clastic wedge in which the Rock Springs, Blair, Ericson, Almond, and other sandstone-bearing units prograded eastward over Hilliard-Baxter-Steele-Mancos marine shales. This play occurs mainly in the eastern and northern parts of the basin. The *Lewis Play* consists of isolated sandstones formed within the Lewis Shale during the transgression that drowned Mesaverde environments. Lewis reservoirs occur in the eastern half of the basin. The *Fox Hills/Lance Play* includes marginal marine and fluvial sandstones that prograded eastward across the Lewis Sea at the close of the Cretaceous. These sandstones are included in the assessment only where overpressured in the deeper parts of the basin. The Tertiary *Fort Union* play is the shallowest unit and is only overpressured in a relatively small area of the southeastern (Washakie) basin center.

Table A2-2: 1989 USGS Greater Green River basin study results

	Cloverly-Frontier	**Mesaverde**	**Lewis**	**Fox Hills Lance**	**Fort Union**
Play Area (ac.)	7,783,000	5,200,000	2,500,000.	2,600,000	331,000
Avg. Thickness	110 ft.	1,350 ft.	400 ft.	675 ft.	600 ft.
Avg. Porosity	5.0%	6.5%	8.0%	7.5%	8.0%
Avg. Depth	17,500 ft.	15,500 ft.	12,000 ft.	10,000 ft.	10,200 ft.
Avg. Gas Sat.	45%	45%	50%	40%	40%
OGIP	304 Tcf	3,347 Tcf	610 Tcf	707 Tcf	96 Tcf
Fut. RF (50^{th}%)	5%	7%	12%	8%	8%
Future RGIP	16.4 Tcf	265.2 Tcf	81.8 Tcf	61.5 Tcf	8.3 Tcf
Curr. RF (50^{th}%)	1%	1%	2.5%	1%	1%
Current RGIP	3.7 Tcf	41.4 Tcf	18.0 Tcf	8.4 Tcf	1.1 Tcf

Play area was determined by identifying the vertical and horizontal distribution of overpressuring and determining how much of the play s sandstone distribution fell within these limits. The authors used whatever data they could gather do to this; often this was mud weight and temperature data, although some DST and pressure-test data were available. Rock thickness was based on sandstone isopach mapping. Porosity distributions by play were generally based on expert opinion informed by assumed porosity-depth relationships. One key assumption of the work is that *the sandstones are assumed to be uniformly gas-charged*. Water saturation is allowed to vary only in relation to estimated porosity and water is assumed to be present only at irreduceable levels. Pressure, temperature and Z-factors are estimated in a standard way. Recovery factors (1% to 5%) were assumed for each play, also as a distribution, for two cases consistent with those used in the Piceance study.

Of course, what makes this study notable, is the magnitude of the total gas-in-place estimate; 5,075 Tcf, more than five times that of the earlier Piceance basin study. Two-thirds of this volume were found to be contained within the various sub-units of the Mesaverde Play. The key parameter estimates and results by play are given in Table 1.

3. 1996 Wind River basin study *(R.C. Johnson and others, Open-file #96-264)*

As with other USGS assessments, the study area is divided into geologic plays that are separately analyzed. Eight stratigraphic units are considered, most with overpressured (equated to areas with temperature of 300 ^{o}F or higher), moderately-pressured (present vitrainite reflectance exceeds 1.1%), and transitional (Ro between 0.73% and 1.1%) plays. Each of the 22 assessed plays is partitioned into numerous sub-plays (analogous to large, irregular, grid cells) to allow for some regional variation in volumetric properties.

The sub-plays are generally areas of relatively consistent drilling depth. For each sub-play, depth, area (closure), pay thickness, porosity, saturation, temperature, pressure, and trap fill (which seems to be analogous to expected dry hole percentages) are estimated. A degree of variance around the estimated mean is also estimated (for example, thickness varies to values plus and minus 50% from the mean at the 5th and 95th percentiles). A single set of variances, as well as temperature, pressure and Z-factor gradients (all linear functions of depth) were used for all sub-plays within each play. Sub-play resources are calculated, then aggregated to provide mean estimates at the play level. Play-level results are then aggregated for the study area. Although the specific report doesn't use the name, this study is the first to use GRASS (the Gas Resource Assessment Spreadsheet System), an Excel application of the USGS probabilistic methodology. It is also the first to use a large number of grid-cell/sub-plays to allow for regional differentiation of input parameters.

Table A2-3: 1996 USGS Wind River basin study results

	Area	**Por**	**Sg**	**Fill**	**F50**	**F95**	**F05**
Frontier - overpressured	2,093	6	50	100	118	76.5	170
Frontier - mod. pressured	695	7	50	100	29.2	18.8	42.6
Frontier - transitional	269	7	50	50	3.6	1.7	7.6
Cody Sh. - overpressured	413	6	50	100	30.6	19.9	44.2
Cody Sh. - m. pressured	413	7	50	70	19.2	12.4	28
Cody Sh. - transitional	233	7	50	30	2	0.8	3.8
Fales SS - overpressured	41	6	50	100	1.2	0.8	1.7
Fales SS - m. pressured	285	7	50	100	7.3	4.7	10.7
Fales SS - transitional	82	7	50	30	0.5	0.2	1.3
Mv-shoreline - o/p	636	6	50	100	34.7	22.6	50.2
Mv-shoreline - m/p	960	7	50	50	17.2	11.1	25.2
Mv-shoreline – trans.	533	7	50	20	3.8	1.6	7.4
Mv-fluvial - o/p	489	6	50	100	48.9	31.9	70.8
Mv-fluvial - m. pressured	1,067				71.8	46.3	105
Mv-fluvial – transitional	582	7	50	50	17.4	7.3	33.5
Meeteetse - o/p	498	6	50	100	51.3	33.4	74.2
Meeteetse - m. pressured	886	7	50	100	59.7	38.4	87.1
Meeteetse – transitional	470	7	50	50	12.5	5.2	24
Lance - mod. Pressured	1,206	7	50	100	316	203	461
Lance – transitional	927	7	50	50	48.9	20.5	94.1
L. Ft. Union – Sealed	1,348	7	50	0-70	83	37.4	153
L. Ft. Union – Unsealed	420	8	50	0-30	18.2	7.7	35.1
Aggregated TOTAL					995	603	1,530

4. 1999 Bighorn basin study *(R.C. Johnson and others; USGS open-file #99-315-A)*

The authors used the scant drillling information available for the central Bighorn basin to guide the USGS fourth Rocky Mountain region volumetric assessment of the in-place resources in a likely basin-centered, low-permeability gas accumulation. Methodological alternations were necessary to accomodate the near lack of real data for this basin.

The resource occurs within the Upper Cretaceous formations ranging from the Frontier (deepest) to the Lance. Much of the accumulation is believed to be normally pressured or underpressured.

A moderately-sized area of overpressuring has been identified below 14,000' in the basin center from mudlog and drillstem test data. As with the Wind River study, sub-thrust areas along the western margin of the basin were not assessed.

Eight plays were identified as follows: 1) Muddy sandstone overpressured, 2) Muddy sandstone transitional, 3) Frontier Formation overpressured, 4) Frontier Formation transitional, 5) Mesaverde Formation overpressured, 6) Mesaverde Formation transitional, 7) Meeteetse Formation, and 8) Lance Formation. The USGS used the GRASS methodology to produce the volume results.

Table A2-4: 1999 USGS Bighorn basin study results

	Area	**Por**	**Sg**	**Fill%**	**F50**	**F95**	**F05**
Muddy - overpressured	889	7	50	100	13.4	8.7	19.6
Muddy - transitional	1,357	7	50	50-70	5.5	2.3	10.0
Frontier – o/p	1,047	7	50	100	41.9	27	61.1
Frontier – transitional	1,937	7	50	50-70	24.6	10.3	47.4
Mesaverde – o/p	301	7	50	100	38.5	24.8	56.2
Mesaverde – trans.	1,781	7	50	20-70	75.8	31.8	146
Meeteetse – trans.	1,805	7	50	50-70	44.9	18.4	86.5
Lance – transitional	1,444	7	50	50-70	89.8	37.6	173
Aggregated TOTAL					334	161	600

The authors speculate that the Bighorn basin contains lower resource volumes, in comparison to the similarly-sized accumulation in the Wind River basin, because of 1) a generally-lower thermal maturity and 2) a lack of widespread overpressuring (only 28% of the appraised resource is from the overpressured plays).

APPENDIX 3: NETL-sponsored Scotia Group reserve assessments (1993-1998)

The objective of these reports was to re-assess the various USGS estimates of total tight gas-in-place in selected western basins and to estimate how much of that gas should be recoverable under current cost and technology conditions. Re-assessment was probably deemed necessary given perceived skepticism over the large volumes presented by the USGS (particularly the 5,000 Tcf GGRB figure). The USGS numbers were indeed revised downward by Scotia, *primarily by showing that the USGS methodology possibly over-estimated typical porosities and water-saturations* in all the basins. The Scotia methodology changed very little with each study, as a result, all four reports are described together.

The Scotia reports used a volumetric approach to determine in-place resources, then applied various cost and performance criteria to partition the resource among different resource and reserve categories. The reports give a single estimate for each resource category, then applies a distribution of recovery factors to obtain different potential-additions-to-reserve numbers, each with a given probability of occurrence.

Like the volumetric USGS studies, subsurface well log correlation and mapping were used to obtain play area estimates. Scotia also used gamma-ray-based (50% cut-off) sand counts to get first approximations of pay thicknesses, and like the USGS, only sands over 10 ft. in thickness were included.   Whereas the USGS relied on a panel of experienced geologists to assign porosities and water saturations to each play, Scotia used log (some core) analyses, tailored for tight sandstone applications, to determine porosities and saturations for various depth ranges within each play. Scotia s data indicated much lower typical porosities and higher water saturations than the USGS had assigned, resulting in significantly lower GIP estimates. Specifically, Scotia found that porosities were not normally-distributed around a mean (as assumed by the USGS), but skewed to the lower values. Also, Scotia determined that the lower-porosity units tended to have higher than expected water saturations.

To high-grade the resource into categories that were likely to contribute to reserves (i.e., contain economically-recoverable gas at current technologies), cut-offs of porosity (varying from 4-10.5% depending on play and depth), Sw (60-65%), and Vsh (35%) were established for separate 500'-thick depth slices. These cut-offs generally attempt to limit the rock volume to that with expected permeability greater than 0.001 md. (Note: for the GGRB study, 1,000' depth slices were used). Porosity and Sw values/distribrutions were generated for both the base resource and technically-viable volumes from digitized well logs. Pressures and temperatures are calculated from gradients to derive Formation Volume Factors. Base resource gas-in-place (in rocks with Vsh<50%) and gas-in-place expected to contribute to reserves (Vsh<35% and porosities and Sw above the depth/play dependant cut-offs) were calculated. Table A3-1 compares the various Scotia estimates with those prepared by the USGS.

Reserves are typically the subset of economically-recoverable volumes that have already been proved by the wellbore. This definition is typically slightly modified for application to the low-permeability, basin-centered resources (the subject of this memo) to account for the vast volumes that have not actually yet been discovered, but are nonetheless, widely accepted to exist.

Table A3-1: Comparison of USGS and Scotia gas-in-place assessments

Basin	USGS GIP estimate	Scotia GIP estimate
Greater Green River	5,064 Tcf	1,974 Tcf
Uinta		396 Tcf
Piceance	420 Tcf	307 Tcf
Wind River	995 Tcf	488 Tcf
Bighorn	334 Tcf	

Scotia further analyzed these resources to determine volumes likely to contribute to reserves. As a first cut, large portions of the resource are excluded as *technically-nonviable* (Table A3-2). Porosity (and associated calculated permeability), saturation, and volume-of-shale cutoffs that varied with depth were used to identify this fraction. It appears that these values are determined based on estimates of how much porosity is necessary in a given depth range to make locations economically-feasible (the assumption is that they must have permeability (estimated from porosity) greater than 0.001 md to be producible at commercial rates given 1993 costs and 1993 capabilities in hydraulic fracturing). Therefore, some of the resource labeled technically-nonviable may in fact be technically possible, but only *economically*-unviable (and only economically-nonviable at the time of the writing).

Table A3-2: Scotia studies **-** distinction of technically viable and non-viable portions of OGIP

	Gas-in-place	Technically-viable	Tech. Non-viable
Greater Green River	1,974 Tcf	848 Tcf (43%)	1,126 Tcf (57%)
Uinta	396 Tcf	71 Tcf (18%)	325 Tcf (82%)
Piceance	307 Tcf	53 Tcf (17%)	254 Tcf (83%)
Wind River	488 Tcf	62 Tcf (13%)	426 Tcf (87%)

Scotia further divided the technically-viable resources into those that occur in reservoirs with demonstrated production and those that, thus far, have not responded to typical completion and stimulation efforts (Table A3-3). The *non-demonstrated resources* are those that *should* be economically-productive based on available data, but have thus far not been economically recoverable in practice. Unexpectedly-high reservoir lenticularity is one prime suspect in making apparently viable resources non-demonstrated.

Table A3-3: Scotia studies **-** distinction of demonstrated and non-demonstrated portions of the technically-viable resource

	Technically-viable	Demonstrated	Non-demonstrated
Greater Green River	848 Tcf	615 Tcf (73%)	233 Tcf (27%)
Uinta	71 Tcf	18 Tcf (25%)	53 Tcf (75%)
Piceance	53 Tcf	45 Tcf (85%)	8 Tcf (15%)
Wind River	62 Tcf	16 Tcf (26%)	45 Tcf (74%)

A further subsidivision (Table A3-4) of the demonstrated resource category is based on the position of the resource relative to a conceptual economic basement . This basement is the depth below which increased drilling costs and technical/geologic risks tend to make average-sized prospects in a particular play *uneconomic*. This depth varies by play, and will change with time as costs and technologies change. *Established resources* occur above the economic basement, *non-established resources* are located below economic basement and above the deepest commercial production. Note that for non-established resources, it is the commerciality that is not firmly established (generally due to depth); the presence and produceability of the gas is generally accepted. *Speculative resources* occur below the deepest commercial production at the date of the report (commerciality is doubtful and gas presence is unestablished). The speculative category was divised after the GGRB study was completed.

Table A3-4: Scotia studies - distinction of established, non-established, and speculative portions of the demonstrated resource.

	Demonstrated	Established	Non-established	Speculative
Greater Green River	253 Tcf	68 Tcf (27%)	185 Tcf (73%)	
Uinta	18 Tcf	4 Tcf (22%)	9 Tcf (50%)	5 Tcf (28%)
Piceance	45 Tcf	9 Tcf (20%)	15 Tcf (33%)	21 Tcf (47%)
Wind River	16 Tcf	8 Tcf (50%)	0 Tcf	8 Tcf (50%)

Calculation of economic basement was done separately for each play. Current EUR distributions were used to estimate the expected revenue. Dry hole risks were assigned to each play (for the GGRB study, all wells in the play were included - the two later studies excluded wells located in non-demonstrated areas). The expected monetary value of production is then plotted versus drilling cost (a proxy for depth) - the point where increasing cost reduces EMV to zero is the economic basement.

Reserves (Table A3.5) are subsets of both the established and non-established resource fractions. These are the maximum volumes that can be profitably recovered assuming a fully efficient drilling pattern and excluding existing wells. Scotia describes that the key factor in estimating reserves in tight sands is the determination of drainage area (and shape) as it relates to the prevailing spacing. The relative recovery of different wells within the drainage area is thought to be consistent (approximately 85%) and a function of the abandonment pressure set by current economics. Decline curves were used to estimate EUR from producing wells, although seasonal curtailment and other external factors complicated this. Average production profiles by play were created and analyzed to determine maximum drainge radius.

Table A3-5: Scotia studies - recoverable reserve (current technology) fractions of the established and non-established resources

	Reserves - established resources	Reserves – non-established resources
Greater Green River	23 Tcf	12.0 Tcf
Uinta	0.9 Tcf	2.3 Tcf
Piceance	2.6 Tcf	3.0 Tcf
Wind River	2.1 Tcf	0.0 Tcf

Table A3-6: Scotia Studies - results by play

	Resources			Reserves	
Play	**Base (Tcf)**	**Viable (Tcf)**	**Establ. (Tcf)**	**Estab. (mean)**	**Non-estab. (mean)**
UINTA: Wasatch	59.9	7.1	3.8	1.33	0.55
UINTA: Mesaverde	335.6	63.6	None	None	1.70
PICEANCE: Marine	85.6	26.6	2.8	0.78	2.16
PICEANCE: Paludal	52.3	8.2	None	None	None
PICEANCE: Fluvial	141.2	13.3	5.7	1.58	None
PICEANCE: Multi-pay	28.2	5.2	0.9	0.20	0.78
WIND RIVER: Frontier	61.1	23.5	1.1	0.53	
WIND RIVER: Cody	61.0	7.4	1.7	0.50	
WIND RIVER: Mesaverde	92.6	5.7	0.3	0.14	
WIND RIVER: Meeteetse	89.7	12.5	None	None	
WIND RIVER: Lance	176.4	11.4	4.3		
WIND RIVER: Ft. Union	6.9	1.0	1.0	0.51	
GGRB: Cloverly/Frontier	285	252	None	None	3.07
GGRB: Mesaverde/Almond	228.2	71.7	40.1	14.2	3.2
GGRB: Mesaverde/Ericson	636.2	231.1	None	None	3.5
GGRB: Mesaverde/Rock S.	102.0	58.0	None	None	None
GGRB: Mesaverde/Blair	7.3	5.0	None	None	None
GGRB: Mesaverde/Undiff.	83.5	26.0	None	None	None
GGRB: Lewis	229	60.0	27.0	8.4	3.6
GGRB: Lance/Fox Hills	349	125	None	None	None
GGRB: Fort Union	54	20	None	None	None

The Scotia work in the Rocky Mountain areas has provided a solid review of the USGS in-place resource estimates. However, Scotia's work clearly does not provide the type of information required by NETL for two reasons. First, in many basins, Scotia qualifies 70% or more of the resource as technically-non-viable. What is missing is an assessment of the specific conditions of the resource that currently makes it non-viable, and what work could be done that could make more of the resource viable. An appraisal that indicated a basin's potential for improving its technically-recoverable resource base would be very valuable to R&D planners. This thinking also applies to the non-demonstrated and non-established portions of the viable resource. What conditions are making the resource too costly to produce, and what degrees/types of technology advancement are needed. The second issue derives from the fact that the Scotia reports imposed current conditions (cost, technology). Because these parameters change with time, the studies can quickly become obsolete.

APPENDIX 4: National Petroleum Council (NPC) Studies

As part of its continuing support of DOE and the Secretary of Energy, the National Petroleum Council (NPC) has prepared three landmark studies over the past 20 years on natural gas that addresses low-permeability resources and reserves.

- The initial study, completed in 1980, was devoted specifically to the size and recoverability of low-permeability resources. It included data on ten appraised basins plus information on other non-conventional sources.
- The second study, completed in 1992 and titled "The Potential for Natural Gas in the United States" re-examined low-permeability resources as part of a larger review of domestic natural gas supplies. This study updated the information on the ten basins appraised in 1980, and added new resource information on the Appalachian, East Texas, Arkansas-Louisiana, Texas Gulf Coast, Anadarko, and Permian basins tight gas formations.
- The most recent, provided in draft form in 1999 and not yet officially released ("Meeting the Challenges of the Nation;s Growing Natural Gas Demand") addresses the key issues surrounding the development of domestic natural gas, including low-permeability resources.

The latest study provided only minor updates to the resource numbers given in the 1992 report, making adjustments only for basins and plays where actual drilling and development results have deviated widely from the 1992 projections.

1999 Study

The 1999 study devoted considerable attention to addressing various conditions that may restrict future gas supply. The NPC found many reasons to be optimistic about the future of gas, as the resource base appears to be sufficient to support high demands, at least through 2015; however, the following issues and concerns were raised:

- Will there be sufficient investment in R&D to maintain the current pace of technology advancement – particularly with respect to domestic, marginal gas resources?
- Are current policies restricting resource development on federal properties appropriate?
- Is the domestic industry capable of drilling the number of wells that will be needed to sustain high supplies given infrastructure limits and the availability of capital?

The NPC study is confident that these challenges can be met, and projects an increase in domestic natural gas production, from 19 Tcf per year currently to 27 Tcf per year in 2015. The increased production is expected to come primarily from three sources:

- Deepwater Gulf of Mexico – a five-fold increase in annual production, from 0.8 Tcf currently to 4.5 Tcf in 2015, is expected.

- Non-conventional resources – nearly doubling in annual production, from 4.4 Tcf currently to 8.5 Tcf in 2015. Specifically, tight gas is expected to grow from 3 Tcf to 5.7 Tcf; gas shales from 0.3 Tcf to 0.7 Tcf; and coalbed methane from 1.1 to 2.1 Tcf per year.

- Deep (greater than 15,000 ft. drilling depth) onshore primarily from the Mid-Continent, West Texas, and Rocky Mountain basins – also nearly doubles in production, from 1.1 Tcf per year currently, to roughly 2 Tcf per year in 2015.

The 1999 NPC study uses a technically-recoverable low-permeability natural gas resource base of 290 Tcf (current technology) to 372 Tcf (expected 2015 technologies: table A5-1, A5-2)

Table A4-1: Technically-recoverable low-permeability resources included in the 1999 NPC study – by resource type (Tcfg).

Resource	Current Technology	Advanced Technology
Tight Gas	177.6	230.6
Gas Shales	38.8	52.6
Coalbed Methane	58.4	74.0
Other	14.7	14.7
TOTAL	289.5	371.9

Table A4-2: Technically-recoverable low-permeability resources included in the 1999 NPC study – by region (Tcfg).

Region	Current Technology	Advanced Technology
Appalachia	13.4	18.3
Arkla – E. Texas	23.6	29.8
Texas Gulf Onshore	8.3	9.1
Rocky Mountains	104.8	137.0
Mid-Continent	12.8	16.9
Permian Basin	14.7	19.5
Lower 48 TOTAL	177.6	230.6

The 1999 NPC study relies heavily on the low-permeability resource volumes developed in the older 1980 study. A few modest adjustments were made when current activity and expectations differed significantly from the 1980 assumptions, as discussed below:

- For tight gas, the changes were modest, primarily reducing tight gas estimates for the San Juan basin. Small upwards adjustments were made for tight gas resources in East Texas and Appalachia.

- For gas shales, potential resources were reduced in the Appalachian basin to reflect recent poor drilling results.

- For coalbed methane, the resource potential in the Warrior basin and the fringe areas of the Fruitland Coal play of the San Juan basin were downgraded. Resources in the Menefee coal of the San Juan were substantially reduced. Resources in the Appalachian and Mid-Continent areas were increased.

1992 NPC Study

The second NPC study incorporated much of the data from the 1980 assessment, gathered industry input for missing tight gas plays, and utilized the 1990-91 ICF data for formations in East Texas and the San Juan basin. The study included only those formations that NPC felt would be likely industry targets through 2010. To determine likely production levels at various price and technology scenarios, NPC utilized GRI/EEA s Hydrocarbon Model. The NPC concluded that 232 Tcf can be extracted from tight gas sands using 1991 technologies. Assuming that technology improvements continued to 2010 at historical rates, NPC estimated that 349 Tcf could be recoverable by 2010 (see Table A4-3).

Table A4-3: 1992 NPC study results (technically-recoverable tight gas at current technology)

	New fields – old plays	Old fields – Old plays	New plays	TOTAL
Appalachia	3.4	0.0	10.5	13.9
Ark.-La.-Tex.	4.2	4.2	19.0	27.4
S. Tex. Onshore	7.1	5.5	5.8	18.4
Williston	0.4	0.3	0.0	0.7
Rockies Forelands	26.4	7.3	89.9	123.6
San Juan basin	1.3	6.5	0.0	7.8
Mid-continent	8.4	2.7	10.8	21.9
Permian	2.3	4.0	12.4	18.7
TOTAL	53.6	30.4	148.4	232.4

The NPC estimated that technology advancements over the preceeding two decades had resulted in the following impacts:

- Reduction in drilling costs of approximately 3 to 4% per year below what they would have been given no technology advance.

- Expansion of the resource base by approximately 0.7% per year.

Both of these historical trends were anticipated to continue, or accelerate, through 2010. Model results indicated that these continued advances would result in a reduction in gas prices of nearly $1/Mcf and a reduction in supply of nearly 3 Tcf per year by 2010. As a result of this technology, the NPC estimated that 349 Tcf of gas could be extracted with 2010 technology. Additional tight gas, bringing the total recoverable to 437 Tcf, could be realized with a "second generation" of advanced technology that were postulated to appear by year 2030.

1980 NPC Study

For their initial work on non-conventional resources, the NPC utilized the Lewin methodology to provide estimates of the tight gas resource potential of 10 high-potential basins (primarily in the Rockies and Texas). These estimates were made for the near-term, single most productive formations that industry would most likely target. The NPC then used these data to guide the assessment to the remaining known tight gas regions in the U.S. The NPC provided estimates for total gas-in-place, maximum recoverable volume, and likely recoverable gas for different cost and technology scenarios. NPC estimated 444 Tcf in-place in the priority basins with an additional 480 Tcf potential in speculative areas. This study excluded resources below 15,000 feet.

Table A4-4: 1980 NPC tight gas resource assessment (values in Tcf gas)

	OGIP	**Technically-Recoverable**	**Base tech. & \$2.50 price**	**Adv. Tech & \$2.50 price**
Appraised				
Great Plains-Williston	147.7	100.1	54.7	74.0
Greater Green River	136.1	86.5	3.1	12.4
Wind River	33.7	23.3	7.0	8.8
Uinta	10.5	15.3	12.2	14.8
Piceance	49.1	33.0	12.9	12.9
Denver	13.2	7.9	0	0
San Juan	3.3	2.2	0	1.5
Val Verde (Ozona/Sonora)	4.5	2.8	0	1.7
Edwards Lime (trend)	14.3	8.7	2.1	8.1
Cotton Valley (trend)	21.9	12.8	5.4	8.4
Sub-total: Appraised	**444**	**292.6**	**97.4**	**142.6**
Extrapolated				
Other Western	69.5	48.9	15.0	17.3
Other Southwestern	183.5	113.4	37.6	87.6
Mid-Continent	8.1	5.4	1.3	4.0
Eastern	227.5	139.9	45.2	107.2
Sub-total: Extrapolated	**480**	**307.6**	**99.1**	**216.1**
TOTAL	**924**	**600**	**197**	**359**

1972 NPC Study

This early study by the NPC did not comment specifically on non-conventional resources.

APPENDIX 5: USGS National Assessments

The USGS included tight gas sandstones for the first time in its 1995 assessment. The method used was much different from the volumetric approach used in the ongoing USGS basin studies described below. Although the play-based approach was retained, a USGS model called UNCLE was used to calculate the probable future additions to reserves from estimates of geologic risk, play area, success rates, and expected EURs. The success ratio and EUR estimates were based on data from existing wells.

Table A5-1: 1995 USGS National Assessment – technically-recoverable resources estimated for continuous-type plays in sandstones

	Technically-recoverable gas (Tcf)		
	95% chance	**5% chance**	**Mean**
Region 2 – Pacific Coast			
05 Oregon and Washington	2.8	30.9	12.2
Region 3 – Colorado Plateau and Range			
20 Uinta and Piceance basins	11.6	23.4	16.7
21 Paradox basin	0.05	0.5	0.2
22 San Juan basin	10.7	36.9	21.2
Region 4 – Rocky Mountains			
28 Central Montana	19.9	79.0	43.2
31 Williston basin	0.1	0.2	0.2
37 Southwestern Wyoming	56.0	213.5	119.3
39 Denver basin	1.5	5.7	3.2
Region 6 – Gulf Coast			
47 Western Gulf	1.8	3.7	2.6
49 East Texas basin	3.6	9.4	6.0
Region 8 – Eastern			
67 Appalachian basin			46.0
TOTAL			**229.3**

Table A5-2: 1995 USGS National Assessment - Greater Green River and Piceance basin results

	Success Ratio	Open 160-acre cells	Mean EUR per cell	Mean adds to reserves
GGRB: Cloverly/Frontier	60%	29,000	1.43 bcf	37.3 Tcf
GGRB: Mesaverde	70%	24,102	1.80 bcf	51.7 Tcf
GGRB: Lewis	70%	13,739	1.31 bcf	19.0 Tcf
GGRB: Fox Hills/Lance	70%	9,500	0.90 bcf	10.2 Tcf
GGRB: Ft. Union	70%	1,180	0.80 bcf	1.0 Tcf
Piceance: Williams Fork	55%	10,304	0.92 bcf	4.9 Tcf
Piceance: Isles	55%	10,508	0.90 bcf	4.8 Tcf

Areas with tight sandstone potential appraised in the 1995 Assessment include: 1) the Williamette-Puget sound area west of the Cascade range, 2) the Columbia basin east of the Cascades, where thick Tertiary fluvial/lacustrine sequences are known to exist beneath the Columbia River basalts, 3) the transgressive Dakota sandstone, the Mesaverde, and the Pictured Cliffs sandstone in the San Juan basin, 4) a possible shallow biogenic gas play in the Niobrara formation along the southern flank of the Williston basin, 5) the lower Cretaceous Muddy (or J) sandstone in the Denver basin, 6) the Cotton Valley Sandstone, which may be locally conventional, in East Texas, 7) the Clinton/medina sandstones and Upper Devonian sandstones of the Appalachian basin, and 8) the Tertiary Wasatch formation and Cretaceous Mesaverde reservoirs in the Uinta basin.

Table A5-3: 1995 USGS national assessment – details on additional areas

Play (cell size in acres)	Play Prob.	Success Ratio	Mean Number open cells	Est. EUR per cell (mean)	Adds to reserves (mean)
Uinta: Wasatch East	100%	88%	1,240	1.40 bcf	2.1 Tcf
Uinta: Wasatch West	100%	30%	1,132	1.35 bcf	0.5 Tcf
Unita: Mesaverde/basin flanks	100%	60%	6,132	1.06 bcf	3.8 Tcf
Uinta: Mesaverde/deep syncline	100%	20%	3,200	1.06 bcf	0.6 Tcf
Columbia River: sub-basalt (160)	100%	70%	7,037	1.42 Bcf	12.2 Tcf
San Juan: Dakota (160)	100%	60%	9,266	1.48 Bcf	8.2 Tcf
San Juan: Mesaverde (160)	100%	55%	7,396	2.36 Bcf	9.6 Tcf
San Juan: Pictured cliffs (160)	100%	50%	7,294	0.90 Bcf	3.3 Tcf
Montana: Bio. gas - hi (160)	100%	80%	7,520	0.90 Bcf	5.4 Tcf
Montana: Bio. gas - med (160)	100%	70%	67,354	0.43 Bcf	2.0 Tcf
Montana: Bio. gas - lo (160)	100%	50%	119,832	0.26 Bcf	1.5 Tcf
Williston: Niobrara (320)	80%	33%	68,752	0.11 Bcf	1.9 Tcf
Denver: J-sand. deep (320)	100%	60%	2,315	0.60 Bcf	0.8 Tcf
LA-Miss: Cotton Valley (640)	100%	100%	1,740	3.47 Bcf	6.0 Tcf
Michigan: Antrim - dev. (40)	100%	99%	15,703	0.32 Bcf	4.9 Tcf
Michigan: Antrim - undev. (80)	100%	80%	54,976	0.32 Bcf	13.9 Tcf
Illinois: New Albany Sh (160)	100%	50%	30,727	0.12 Bcf	1.9 Tcf
Cinc. Arch: Dev. Sh. (160)	50%	50%	45,046	0.12 Bcf	1.4 Tcf
Appalachia: Clinton - hi (40)	100%	90%	224,287	0.12 Bcf	24.6 Tcf
Appalachia: Clinton - med (40)	100%	70%	108,939	0.08 Bcf	5.7 Tcf
Appalachia: Clinton - lo (40)	50%	30%	124,550	0.05 Bcf	0.9 Tcf
Appalachia: U. Dev. - hi (40)	100%	80%	147,758	0.08 Bcf	10.0 Tcf
Appalachia: U. Dev. - med (40)	100%	50%	91,046	0.08 Bcf	3.8 Tcf
Appalachia: U. Dev. - lo (40)	50%	30%	124,061	0.05 Bcf	0.9 Tcf
Appalachia: Big Sandy (150)	100%	90%	13,429	0.60 Bcf	9.1 Tcf
Appalachia: Silt/Sh. (60)	100%	85%	35,454	0.09 Bcf	2.8 Tcf
Appalachia: Lo-T.M. Sh. (150)	100%	70%	39,500	0.12 Bcf	3.5 Tcf

Specific findings of the USGS relative to low-permeability formations are as follows:

- An unlikely extraction effort would be required to obtain the gas – amounting to 960,000 productive wells and 570,000 dry holes.

- Most low-permeability sandstone gas would be extracted from a relatively small subset of the productive wells: 50 % of the recoverable resource would be produced from 100,000 wells averaging about 1.5 Bcf per well; or 75% would be produced from 250,000 wells that would average about 0.5 Bcf per well.

- The USGS's economic analysis of the low-permeability resources (Circular 1145) judged that only 21 Tcf of the resource was recoverable at $2.00/Mcf gas price. A rise in price to $3.34/Mcf was expected to add only 7.5 Tcf additional gas.

- Of the 28.5 Tcf recoverable at $3.34/Mcf price, 11.7 Tcf occurred in the San Juan basin, 5.5 Tcf in the Louisiana-Mississippi Salt basins, and 5.2 Tcf from Central Montana. The Rocky Mountain region contributed only 5.5 Tcf with 3.3 Tcf from southwestern Wyoming and 2.2 Tcf from Uinta-Piceance.

APPENDIX 6: Advanced Resources International (ARI) Partitioning Study of the Greater Green River Basin

ARI's analysis of the Greater Green River Basin had three objectives:

- Update the gas-in-place estimates for two of the major formations – the Mesaverde and the Frontier – focusing only on the overpressured zones.

- Assemble information of the key reservoir parameters governing recovery from these formations

- Provide estimates of recoverable resources using current and advanced E&P technology characterizations.

The partioning study divided the GGRB into 20 geologically-consistent areas based on structural features, deposition, depth, reservoir pressure, and other information. A series of base maps were prepared to calculate gas volumes in-place in each partition. A structural overprint of the basin was completed using satellite imagery, aeromagnetic and gravity data and was used to rank each partition according to its estimated potential for natural fracturing. Historical drilling and production data were then used to estimate expected well performance in each area.

The study reported 1,005 Tcf gas-in-place in the Mesaverde and 213 Tcf gas-in-place in the Frontier (Table 6-1).

Table 6-1: ARI partitioning study results (values in Tcf gas)

Partition	**Mesaverde**			**Frontier**		
	Gas-in-place	Tech-rec. CurrTech	Tech-rec. adv. tech.	Gas-in-place	Tech-rec. CurrTech	Tech-rec. adv. tech.
Pinedale	238	19.2	27.1	17	0.8	4.7
Sand Wash deep	89	13.1	18.2	8	1.3	2.2
Hoback	197	11.1	15.8	29	2.4	4.2
Wamsutter Arch	63	7.1	9.4	7	3.2	1.9
Farson deep	80	6.0	18.1	23	1.0	4.6
Red Desert	181	12.7	8.5	43	2.4	7.0
Cherokee Arch	13	2.5	12.0	2	0.7	0.6
East Sand Wash	37	3.3	4.7	7	0.7	1.3
Washakie deep	84	8.4	3.5	12	0.2	2.4
East Washakie	23	2.1	3.0	4	0.4	0.6
Red Desert deep	10	0.8	1.1	9	1.3	1.0
Green River deep				24	0.9	5.5
Vermillion				11	4.0	1.8
West Washakie				4	1.1	1.4
West of Moxa Arch				12	2.7	1.7
Dad dix				2	0.4	0.6
TOTALS	**1,005**	**86.4**	**121.4**	**213**	**23.4**	**41.2**

The key findings and conclusions of the ARI partitioning study are as follows:

- A structural interpretation of the basin is essential for estimating the key parameter controlling well performance – natural fracture enhanced reservoir permeability.

- The following are the three most essential technology advances; 1) identification of naturally-fractured areas prior to drilling; 2) utilization of horizontal drilling technologies; and 3) cost reduction for multiply-completed vertical wells in which thick vertical columns of stacked sandstones exist.

APPENDIX 7: Preliminary Analyses of Long-term Sustainability Issues

Preliminary analyses using GSAM were conducted to provide insight on the current capabilities and outputs of the model. Three key issues pertaining to using GSAM for the analyses described in the body of the report are:

- How much of the current OGIP is included in the models resource?

- How disaggregated is the current database (will it be sufficiently sensitive to incremental technology advances)?

- What are GSAM's current capabilities relative to federal land access?

1. Resource volumes

GSAM uses a highly detailed characterization of the natural gas resource base. Resource volumes (OGIP of included reservoirs) output from GSAM's current base case are shown in Tables A7-1 and A7-2. Data sources are as follows:

- *Discovered reservoirs (non-Appalachia):* from NRG Associates (release 14).
- *Discovered reservoirs (Appalachia):* estimated from Gas Atlas and other sources.
- *Non-conventional reservoirs:* estimated from USGS 1995 national assessment
- *Undiscovered onshore reservoirs:* estimated from USGS 1995 national assessment
- *Undiscovered offshore reservoirs:* from MMS databases
- *Canadian reservoirs:* from NRG and CGS databases.

Table A7-1: GSAM resource base by resource type (values in Tcf OGIP, 2000)

Resource Segment	Undiscovered	Discovered	Res. Growth	TOTAL
US Conventional	179.1	114.5	143.6	437.2
US Tight	592.7	91.4	74.9	759.0
US Naturally-fractured	3.4	1.7	1.3	6.4
US Water drive	11.2	2.7	2.5	16.4
US Coals and shales	51.7	25.9	18.2	95.8
US Offshore	225.7	91.1	90.7	407.5
TOTAL US	1,063.7	327.3	331.1	1,722.1
Canada Conventional	205.4	72.6	83.6	361.6
Canada Tight	11.6	2.4	4.0	18.0
Canada Naturally-fractured	54.8	15.9	22.7	93.4
Canada Water drive	-	-	-	-
Canada Coals and shales	432.4	-	223.3	655.7
Canada Offshore	-	-	-	-
TOTAL CANADA	704.1	90.9	333.6	1,128.6

Table A7-2 GSAM Resource base (values in Tcf estimated for year 2000)

Resource Segment	Undiscovered	Discovered	Res. Growth	TOTAL
Pacific, Atlantic offshore	-	-	-	-
Pacific onshore	7.3	8.2	13.1	28.6
San Juan basin	44.1	15.7	7.7	67.5
Rockies Foreland basins	476.5	42.1	60.5	579.1
Williston basin	64.2	18.0	0.4	82.6
Permian basin	15.4	21.5	33.3	70.2
Mid-Continent	15.9	32.8	51.1	99.8
Arkansas-Louisiana-E. Texas	7.5	22.4	21.7	51.6
Texas Gulf Coast	44.9	23.5	23.0	91.4
Western Gulf of Mexico	99.3	37.2	33.7	170.2
Central Gulf of Mexico	126.4	54.0	57.0	237.4
Eastern Gulf of Mexico	-	-	-	-
Norphlet	-	-	-	-
Louisiana Gulf Coast	36.6	12.2	9.4	58.2
Miss., Ala., Florida onshore	23.8	6.9	6.7	37.4
Mid-West	13.2	10.8	11.0	35.0
Appalachia	88.7	22.1	2.6	113.4
Alberta	647.7	76.5	306.0	1,030.2
British Columbia	56.5	14.3	27.6	98.4
North Alaska, MacKenzie delta	-	-	-	-
Mexico	-	-	-	-

GSAM's resource volumes are greater than the existing assessments (USGS, PGC, NPC) simply because GSAM is designed to work with original-gas-in-place volumes. However, the primary data source for the undiscovered resource (which drawfs the discovered resource in terms of volumes) are the "technically-recoverable" estimates from the 1995 USGS national assessment. Therefore, GSAM converts the USGS volumes to OGIP by multiplying the recoverable numbers by a multiplier that estimates recovery factors. This method gives an estimate of OGIP only for those reservoirs that are included in the recoverable estimates, thereby excluding large volumes of sub-economic resources. (Compare the 579 Tcf gas included in GSAM for the Rocky Mountain regions to the 8,000 Tcf in-place estimated by the USGS for the same area).

GSAM also does not capture various resources that need to be considered in modeling long-term (2020-2050) gas issues. These missing resources include tight gas resources in the Powder River, Wind River, Bighorn, and other western basins that were not included in the 1995 USGS assessment. Similary, GSAM contains no gas for the offshore moratoria areas of the Atlantic, Pacific, and eastern Gulf of Mexico. GSAM also has no North Alaska gas. Finally, GSAM contains no characterization of methane hydrates resources.

Therefore, in the short term, work will be conducted to expand the OGIP included in the database for undiscovered reservoirs. Initial work will focus on the Rocky Mountain region: both in adding missing resources and in upgrading the data present. Subsequent project phases will address additional high-risk, speculative, or currently off-limits resources as indicated by the ongoing tracking studies and selected by the project leadership team.

2. Disaggregation

GSAM's undiscovered databases for the Rocky Mountain region were reviewed to determine the degree of disaggregation present. Table A7-3 summarizes the data for tight formations.

Table A7-3: GSAM's resource characterization for tight formations in the Rocky Mountain region.

Play	Perm. (md)	Por.	Gas Sat.	Depth (ft.)	Press. (psi)	Temp. (F)	Number Pri./Fed.	Resource (Tcfg)
Piceance: Williams Fork	0.01	10%	50%	7,600	3,556	212	41/53	6.92
Piceance: Iles	0.1	15%	60%	7,800	3,644	216	39/53	7.83
Uinta: Tertiary East	0.1	20%	50%	5,400	2,528	168	10/39	3.95
Uinta: Tertiary West	0.1	18%	60%	6,000	2,807	180	5/17	1.14
Uinta: Mesaverde basin flank	0.08	18%	60%	11,900	5,551	298	68/109	10.99
Uinta: Mesaverde deep syn.	0.07	18%	60%	18,400	8,573	428	31/2	2.04
GGRB: Cloverly-Frontier	0.1	15%	50%	16,900	7,883	398	64/193	85.34
GGRB: Mesaverde	0.2	17%	50%	8,613	4,699	173	302/1207	156.93
GGRB: Lewis	0.06	11%	60%	12,900	6,026	319	45/140	34.76
GGRB: Fox Hills/Lance	0.13	16%	40%	11,300	5,282	287	31/128	16.79
GGRB: Fort Union	0.06	12%	60%	11,200	5,233	284	13/19	2.01
Denver: J-Sandstone deep	0.05	12%	50%	7,700	3,600	214	62/3	1.39

Currently, all 1,509 reservoirs available for discovery in the Mesaverde Formation of the Greater Green River basin are characterized with identical permeability, porosity, gas saturation, depth, pressure and temperature. What currently distinguishes them is size – each reservoir is assigned to one of 13 field size classes. Both area and pay thickness increase systematically with class. The treatment for the 37 conventional undiscovered plays in the Rocky Mountain region is similar. GSAM's original developer, ICF Consulting, has studied a methodology for improving this characterization by varying selected parameters with field size class based on the geologic literature. This project will work to produce this resource disaggregation through direct analyses of geologic data, and will focus particularly on parameters that directly impact reservoir productivity (effective fracture permeability, for example) and cost (depth).

Also under review will be the method in which GSAM describes tight resources. Currently, both conventional and non-conventional resources are described relative to 13 field size classes. This method is clearly appropriate for conventional reservoirs, but may not be suitable for the basin-centered deposits. Alternatives (perhaps replacing field size with well productivity) will be pursued.

Additional modeling work will include review and improvement of GSAM's handling of horizontal wells, the procedures for reserves booking, the treatment of alternative well spacings, and allowances made in the model to handle multiple or sequential completion of stacked reservoirs.

3. Federal lands

GSAMs database for discovered reservoirs contains a flag (P or F) that identifies the reservoir as either occuring on private or federal land. The undiscovered resource database has been split into two separate databases, one for federal – one for private. The databases are virtually identical except in the number of reservoirs attributed to each size class.

GSAM can model Federal land issues directly in the RP module by applying unique advanced technology cases to the Federal land resource database (this will work only for the undiscovered resource). Or, a single advanced technology scenario can be applied, but the availability of resource available for discovery can be controlled separately in the E&P module using unique technology penetration and resource availability schedules.

Preliminary analyses with GSAM were conducted using the default base case to test the current capabilities of the model relative to Federal lands. The base case is unchanged from that provided by ICF in March 2000. Three scenarios were tested with the results summarized in Table A7-4.

- Incremental technology penetration for onshore Federal lands: Advanced technology was used sooner and more often by a factor of 5% (in each year, 5% more of the resource is explored and developed under the assumed benefits of the RP module's advanced technology scenario).

- Increased resource base: GSAM's resource base for the Rocky Mountain region was increased by 137 Tcf. This run simulates the impact of adding 137 Tcf of resource. The 137 Tcf value is derived from the NPC's preliminary estimate of the restricted resource on Federal lands in the region.

- A combination of increased resource base and faster technology penetration.

The runs indicated that each year, at given (AEO 99) prices, incremental production from 60 Bcf to 120 Bcf can result from accelerating technology penetration alone. The addition of 137 Tcf of gas resource to this case greatly increases the estimated impact, ranging up to 600 bcf per year with a cumulative production increase of nearly 8 Tcf in the period from 2000 to 2020.